Review of NESO’s frequency containment provisions and the Frequency Risk and Control Report 2025

Keith Bell, University of Strathclyde

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About the author

Keith Bell holds the Scottish Power Chair in Future Power Systems at the University of Strathclyde where he has been since 2005. He gained his PhD at the University of Bath in 1995 and then worked as a post-doctoral researcher at the University of Manchester and in Naples and as a system development engineer with National Grid.

Keith is a co-Director of the UK Energy Research Centre and, in April 2019, became a member of the UK's Climate Change Committee. He is a Chartered Engineer and a Fellow of the Royal Society of Edinburgh. He has advised the Scottish, UK and Irish governments and Ofgem on electrical energy and power systems issues and is active in CIGRE, the International Council of Large Electric Systems. He is also on the Executive Committees of the IET Power Academy, an initiative to encourage graduate engineers into the power and energy sector, and the Power Systems Computation Conference. He was on the Electricity Networks Commissioner's advisory group between October 2022 and June 2023 and is a member of Ofgem's climate resilience expert panel.

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Executive Summary

Risks of interruptions of supply of power from Great Britain's (GB) electricity transmission system to distribution networks or directly connected users of electricity, of voltages on the network deviating beyond acceptable limits and of the system becoming unstable – including the risk of frequency instability – are managed in ways set out in the National Electricity Transmission System (NETS) Security and Quality of Supply Standard (SQSS) [1]. In general terms, the SQSS defines a set of 'secured events' that might occur on the system and specifies limits to the impacts these events might cause, such as the maximum or minimum value of system frequency. If any of those events, were they to happen, would lead to one of the proscribed outcomes, the National Energy System Operator (NESO) is obliged to take action to change the operating state of the system such that those outcomes would not occur. In many cases, those actions incur a cost to NESO that is then recovered from transmission network users.

In 2021, the forerunner to NESO proposed that deviations of system frequency on the GB electricity system should be managed in such a way as to balance risks associated with large deviations with costs of containing deviations, reviewing that balance periodically [2]. Moreover, a "Frequency Risk and Control Report" (FRCR) would be produced on a regular basis setting out the system operator's approach to doing that and providing justification for the policy arrived at for managing system frequency. The first FRCR was published in April 2021 and, following a consultation and approval by Ofgem, reference to FRCR to set out the terms under which system frequency deviations would be contained was added to the SQSS.

NESO's FRCR 2025 [3] proposed that the amount of money spent on re-dispatch actions to ensure a certain minimum level of system inertia could be reduced by an estimated £96m per year by reducing the minimum from 120 GVA.s to 102 GVA.s. The report also argued that the probability of system frequency falling to 49.2 Hz or to 48.8 Hz and of frequency rising to 50.5 Hz or above was small and, hence, risks to stable system operation resulting from a reduction in system inertia are small. However, a number of respondents to consultations on the proposal conducted by both NESO and Ofgem raised concerns with it or with the way it had been arrived.

To inform Ofgem's own evaluation of the proposal, Ofgem has commissioned an independent review of NESO's proposal and the evidence provided by NESO in support of it. This report presents the findings of that review.

The 'inertia' of a power system refers to the kinetic energy stored in the rotating mass of each electrical machine that is released or absorbed as conditions on the system change (provided the machines' physical rotation remains synchronised with the alternation of voltages on the network). This store of energy helps to smooth out variations of power on the network. However, while very useful, it is not true that it is utterly essential to stable operation of system: any store of energy will do, provided it can be accessed quickly enough, either to discharge it or charge it, and there is enough of it.

On the GB power system, there will still be a significant amount of inertia for some years to come but, if full use is to be made of the available wind and solar power, we need to learn how to stabilise the system with minimal amounts of it. Experience in GB over recent years suggests that NESO has been doing exactly that, making use of batteries to provide rapid frequency containment reserve – Dynamic Containment.

The main conclusions arising from the review described in this report concern four areas.

1. It is right that obstacles to utilisation of renewable energy and reduction of costs of system operation are removed. In broad terms, the author of this review agrees that this can be done without unduly increasing risk.
2. The principles driving the Frequency Risk and Control Report (FRCR) represent a good general approach to articulation and management of risk, postulating that:
    a. the benefits of reducing system risk should be balanced with the cost of achieving that reduction; and
    b. risk can be quantified in terms of the impact resulting from a particular disturbance multiplied by the probability of that disturbance.

    Furthermore, it seems reasonable that impact in terms of frequency deviation should be quantified in terms of rises above 50.5 Hz and falls (a) below 49.5 Hz and above 49.2 Hz; (b) below 49.2 Hz but above 48.8 Hz; and (c) below 48.8 Hz.
3. The evidence in support of the assertion that reduction in system inertia would not unduly increase system risk is mostly centred on a reasonable set of factors but is not presented sufficiently clearly to give stakeholders full confidence in the level of risk to which the system is being exposed. This includes evidence that simulations are sufficiently accurate in reproducing a wide range of real events; that probabilities of different disturbances are as they are claimed to be; and that load inertia is a particular value under a wide range of operating conditions. Moreover, some significant factors relating to the impact of disturbances on system frequency are not addressed sufficiently clearly, most notably:
    a. the potential for local variations of voltage magnitude and voltage angle to trigger Rate of Change of Frequency (ROCOF) or Vector Shift (VS) based Loss of Mains protection on distributed generation (DG); and
    b. whether Low Frequency Demand Disconnection (LFDD) as configured today is fit for the purpose of preventing frequency collapse on a system that has low inertia and a large amount of distributed generation that would be disconnected by the action of LFDD relays.

    In relation to factors that are not modelled explicitly, it would be reasonable to make some conservative assumptions. In many instances, this seems to have been done but could have been explained more clearly in published FRCR reports.
4. The framing of statutory requirements around management of system frequency is insufficiently clear to ensure that an event investigation could draw firm conclusions about the actions that a system operator was supposed to take.

A number of recommendations are made, as priorities for the completion of the FRCR 2025 process and to inform subsequent FRCRs. Recommendations for FRCR 2025 are:

1. Revise and re-publish the FRCR 2025 Report and associated Methodology and Data documents to include evidence of validation of simulations and greater clarity on estimation of probabilities and system parameters, noting, in particular, where conservative assumptions have been made and the nature and impact of those assumptions.
2. Publish an update on what the most recent review of LFDD found, what changes were recommended and whether those changes have been carried out.
3. Provide evidence on the effectiveness and reliability of Dynamic Containment (DC) under a wide range of system conditions.

Recommended actions for NESO to inform FRCR 2026 are:

1. Investigate the extent to which generators, interconnectors and storage assets fail to ride-through system disturbances in the ways they are required to by the Grid Code and propose ways to improve compliance.

2. Ensure that lessons from the collapse of the power system on the Iberian Peninsula are captured and implemented, including any arising from a review of risks associated with temporary over-voltage that could lead to losses of infeed.
3. Ensure that system modellers and engineers responsible for the development of policy, e.g. on frequency risk management, have convenient access to archives of operational data.
4. Improve how the SQSS panel performs in driving and scrutinising changes to the SQSS.
5. Take steps to improve the clarity of the licence framing of frequency management by reducing or removing ambiguity from the SQSS.

Actions by NESO and the GB electricity sector more generally recommended to inform subsequent FRCRs are:

1. Lead a sector-wide update, to be completed during 2026, to the most recent review of LFDD to assess a wide range of likely future system conditions and extend it to address high frequency risks that could lead to rapid falls in system frequency. The sector should ensure that steps recommended to improve performance are implemented in a timely manner.
2. Ensure that NESO has reliable measurement or state estimation in real-time of power flows at every grid supply point.
3. Ensure that NESO has reliable data on the type and capacity of distributed generation and storage at every grid supply point and that its dynamic behaviour, including in response to transmission network disturbances, is adequately managed by provisions in the Grid Code and/or Engineering Recommendations such that risks to transmission system stability are acceptable.
4. Take steps to assure: NESO's access to sufficiently detailed models of network users' assets; the reliability of controller software deployed by network users and providers of system services; adequate management of controller software updates.
5. Investigate the potential for significant low voltage induced frequency deviation in future operating conditions with a significant total 'system non-synchronous penetration'.
6. Investigate the potential for faults to cause large phase angle jumps that trigger disconnections of inverter-based resources.
7. Conduct an investigation into wholesale market-related risks to system frequency associated with:
    a. 'smart' tariffs for demand causing coherent switching behaviour among a large number of loads leading to large step changes in demand at the start of a market settlement period, and how such risks might be mitigated, e.g. by imposing small, random delays on the switching of individual loads;
    b. behaviour by generators in receipt of Contracts for Difference (CfDs) that cut revenues when the relevant reference price is negative for a successive number of settlement periods.
8. Ensure that risks associated with disconnection and reconnection of large loads are well-managed.
9. Lead a discussion on what combination of probability and impact represents an acceptable or unacceptable risk.

1 Introduction

Risks of interruptions of supply of power from the GB electricity transmission system to distribution networks or directly connected users of electricity, of voltages on the network deviating beyond acceptable limits and of the system becoming unstable – including the risk of frequency instability – are managed in ways set out in the National Electricity Transmission System (NETS) Security and Quality of Supply Standard (SQSS) [1]. As will be discussed in sections 2.4 and 3.1 of this report, in general terms, the SQSS defines a set of 'secured events' that might occur on the system, and specifies limits to the impacts these events might cause, such as the maximum or minimum value of system frequency. If any of those events, were they to happen, would lead to one of the proscribed outcomes, the National Energy System Operator (NESO, referred to in the SQSS as the Independent System Operator and Planner, *ISOP*) is obliged to take action to change the operating state of the system such that those outcomes would not occur. In many cases, those actions incur a cost to NESO that is then recovered from transmission network users.

In 2021, the Electricity System Operator part of National Grid (NGESO prior to becoming NESO[1]) proposed that deviations of system frequency on the GB electricity system should be managed in such a way as to balance risks associated with large deviations with costs of containing deviations, reviewing that balance periodically [2]. Moreover, a "Frequency Risk and Control Report" (FRCR) would be produced on a regular basis setting out the system operator's approach to doing that and providing justification for the policy arrived at for managing system frequency. The first FRCR was published in April 2021 and, following a consultation and approval by Ofgem [4], reference to FRCR to set out the terms under which system frequency deviations would be contained was added to the SQSS.

The main tools used by NESO in limiting the magnitude of frequency deviations following any kind of disturbance to operation of the system are:

1. The procurement of frequency containment reserve, i.e. 'headroom' for extra power production or reduced demand in the event of frequency fall, or 'footroom' for reduced power production or extra demand in the event of a frequency rise.
2. Action to re-dispatch generation, interconnector transfers, flexible demand or charging or discharging of energy storage in order to reduce the potential size of a single 'loss of infeed' (loss of power being injected into the system) or 'loss of outfeed' (loss of power being taken from the system) disturbance so that the consequential frequency deviation is reduced.
3. Action to re-dispatch generation, interconnector transfers, flexible demand or charging or discharging of energy storage in order to increase system inertia so that the rate of change of frequency (ROCOF) and the likely magnitude of frequency deviation resulting from any given disturbance would be reduced.

NESO's FRCR 2025 [3] proposed that the amount of money spent on re-dispatch actions to ensure that system inertia is always at a certain minimum level could be reduced by an estimated £96m per year by reducing the minimum level of inertia from 120 GVA.s to 102 GVA.s. The report also argued that the probability of frequency falling to 49.2 Hz or to 48.8 Hz and of frequency rising to 50.5 Hz or above was small and, hence, risks to stable system operation resulting from a reduction in system inertia are small.

[1] NGESO became the National Energy System Operator (NESO) in October 2024.

NESO's proposal was published on 3 March 2025 with comments invited by 7 April 2025. Seven responses were received, broadly in favour but with some concerns raised[2]. It was then first put to the SQSS Panel on 6 May 2025. Four members voted in support of it; three members abstained.

Ofgem has since conducted its own consultation on the proposed change to minimum system inertia. Fifteen responses were received: 6 in favour; 9 against[3].

To inform Ofgem's own evaluation of the proposal, Ofgem has commissioned an independent review of NESO's proposal and the evidence provided by NESO in support of it. The following sections of this report summarise the findings of that review. (See Annex 2 for the Terms of Reference of the review).

This report starts, in the next section, with a discussion of some of the main principles that underpin operation of a power system in general and the GB system in particular. It then goes into more detail on the general approach to managing system frequency and the aims of FRCR. The next two sections after that discuss various notable issues raised by some of the respondents to NESO's FRCR 2025 consultation and Ofgem's related consultation, and points of discussion that have occurred to the author of this report. Finally, in section 7, some conclusions are drawn and recommendations made.

[2] For consultation responses and NESO replies, see https://www.neso.energy/industry-information/codes/security-and-quality-supply-standard-sqss/frequency-risk-and-control-report-frcr
[3] See https://www.ofgem.gov.uk/consultation/frequency-risk-and-control-report-2025

2 Principles in power system risk management

2.1 Containing the impacts of disturbances

Power systems are subject to all sorts of disturbances that change the state of the system. Continued stable operation depends on the system settling to a new steady state that is within the safe operating limits of all the equipment connected to the system. Some automatic equipment controls, e.g. an excitation system on a synchronous generator or the current control loop on a power electronic inverter, act to ensure that the equipment's physical limits are respected. On other equipment or for other aspects, equipment protection would operate to disconnect the equipment in the event of a limit being breached, e.g. over-current protection on a transformer, underground cable or overhead line, or under-voltage, over-voltage, under-frequency or over-frequency protection on a generator.

The sorts of changes or disturbances that a power system is subject to range from the very small, e.g. a single domestic light bulb being switched on or off, to the very large, e.g. a large nuclear power station suffering a forced outage. A key part of a system operator's job is to ensure that disturbances would not cause the power system to become unstable. In a worst case, a disturbance might lead to collapse of the whole system and zero volts being supplied to all the loads connected to it. ideally, no disturbance would lead to interruption of supply to any demand, i.e. electrical loads served from the network. However, to guarantee that for all possible disturbances is impossible. Instead, a judgment must be made on the costs and benefits associated with different actions to limit risk.

2.2 Quantifying risk

For an engineer, the risk to which a system is exposed when it is operating in a particular condition could, in principle, be quantified as the product of the probability of a disturbance and some measure of its impact, summed over all possible disturbances.

In practice, for a large power system such as that in GB, an assessment of the potential impacts of all the ways in which the system might be disturbed from any, given initial condition and of all the ways in which the initial condition or responses to disturbances might be changed in order to prevent or contain adverse impacts is extremely difficult. Instead, system operators around the world follow what are often referred to as 'security standards', of which the SQSS in GB is an example. These approximate a boundary between acceptable and unacceptable risks in relation to defined subsets of all possible events – those that are typically regarded as being most 'credible' or likely – and oblige the system operator to take action to limit the impacts they would cause.

Figure 1 illustrates the 'risk space' and a boundary between acceptable and unacceptable. In the figure, the x-axis represents the probability of a disturbance or event, and the y-axis its impact, in this case how much power would be disconnected at the moment when any dis-connection of demand happens. For a given initial state of the system (and ambient conditions), every possible disturbance could, in principle, be visualised as a point in that space.

The 'isorisk' curve represents a constant value of risk. A policy judgment would determine that the risk associated with any event lying above and to the right of that curve would be unacceptable. That is, the system operator must take action to change the initial state of the system or put in place corrective measures to move the event below that curve and to the left.

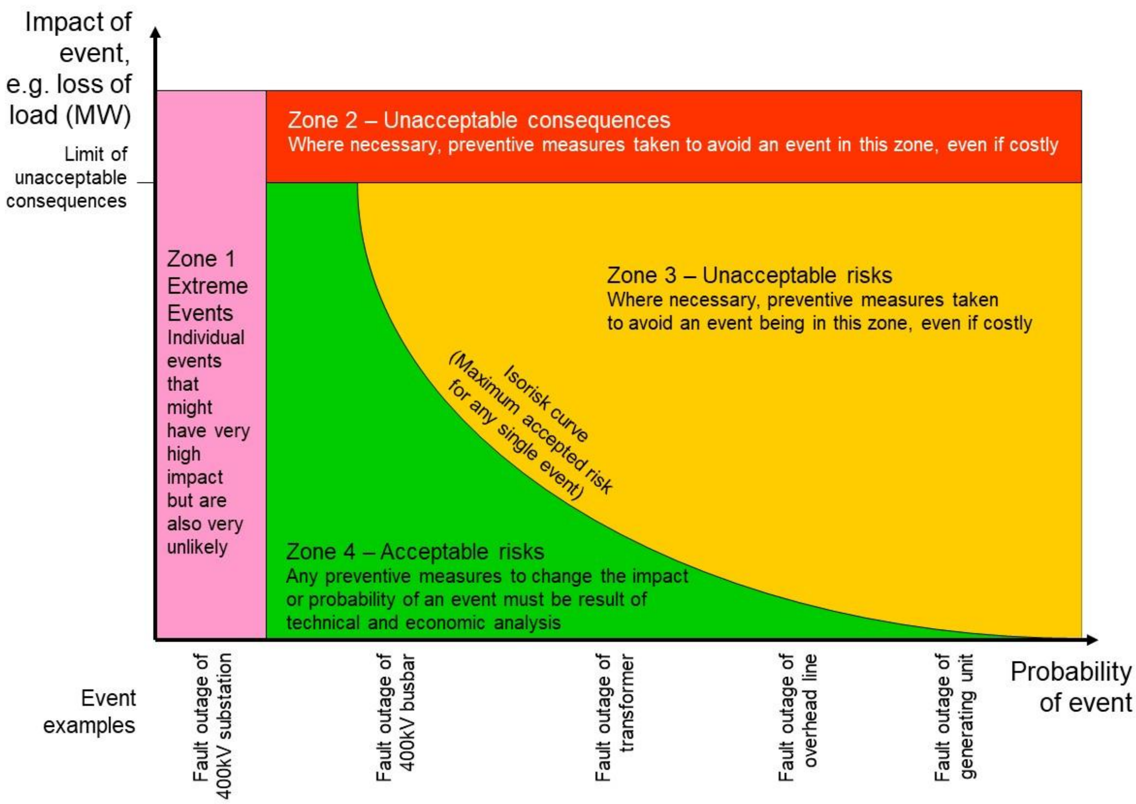

Figure 1: Visualisation of the risk associated with any given disturbance to operation of a power system. Source: [5]

2.3 Reducing risk

An example of an action to reduce risk is the re-dispatch of pre-event power flows such that, following a given event, such as a short circuit fault somewhere on the network and the successful operation of protection on any directly affected equipment to remove that equipment from service, post-event power flows would be within the thermal ratings of all branches of the network. In that condition, the system operator can be confident that no other protection would operate and, given sufficient damping of transient variations to voltages and currents caused by the fault, the system will settle to a new steady state. If an outage of the initially faulted branch did not disconnect any load, all load would be successfully supplied.

As can be seen from that example, one key thing to take into account when assessing the impact of a disturbance is the response of automatic equipment for control and protection of the system and its component parts. Depending on the time period over which protection might be expected to operate and, potentially, make the impact of a disturbance worse, manual action by the system operator might also be possible as a way of containing an impact. An example of that would be a power flow on an overhead line that is above the continuous thermal rating – the level of current that can be sustained indefinitely without exceeding the safe conductor temperature – but within the 20 minute rating. If the system operator can take action to correct the power flow down to within the continuous rating in less than 20 minutes, in principle all should be well.

Instead of taking action to reduce the impact of a disturbance, in theory, the likelihood of the disturbance could be altered. One obvious example would be action to maintain a particular item of equipment such that it is less likely to develop a fault. For equipment exposed to the elements, weather conditions can dramatically change the probability of a fault. For example, for an overhead line, the average rate of occurrence of a fault can be 1000 or even 10000 times higher in 'adverse' weather (such as electrical storms or very high winds) than in 'normal' weather [6]. However, a 'hardened' design of equipment – e.g. built with higher mechanical, strength or greater electrical insulation – can reduce the likelihood of particular conditions causing a fault outage.

Figure 1 also shows two other regions: one in which the probability of a disturbance is regarded as being so small that it does not merit attention; the other in which, regardless of the cause or its probability, the impact is regarded as so large as deserving action to reduce it. The former can be thought of representing very large scale, 'force majeure' disturbances. The latter is typically dealt with by the design and installation of 'defence measures' such as automatic under-frequency load-shedding that would, in a last resort, correct an imbalance between generation and demand in which demand exceeds generation by disconnecting some part of the demand. In GB, this measure is referred to as Low Frequency Demand Disconnection (LFDD). It has 8 different stages, defined in the Grid Code [7], the first of which operates when system frequency is at or below 48.8 Hz for a given period of time. (The other stages disconnect additional demand and are triggered at progressively lower levels of system frequency).

One limitation with Figure 1 as a way of visualising risk is that while it might be clear in respect of the risks associated with single events, what counts is total system risk, i.e. that arising from all possible disturbances, is not easily seen. Action to reduce risk associated with one might increase risk associated with another.

A further challenge is the judgment around what is the acceptable level of risk. In principle, a monetary value could be put on continuity of supply to demand, or a cost on interruptions to supply. The benefits of reducing the expected magnitude of power or energy not supplied might be compared with the costs of achieving that reduction, e.g. through re-dispatch of generation. (See, for example, [8]). However, in practice, it is difficult to be confident on what the 'value of lost load' would be: the impact on different energy users depends on what they are doing with the energy, whether they have access to alternative ways of meeting that need and how long the outage lasts.

A final issue with security standards is that they are commonly regarded as only requiring assessment of the impacts of certain events – in SQSS terms, 'secured events'. Total risk associated with other events or combinations of events – the 'residual risk' – is usually not explicitly addressed and is implicitly assumed to be small. (See [9]).

2.4 How the SQSS articulates the management of risk

The basic framing of risk in the SQSS is most clearly articulated in the main chapter on operation of the system: chapter 5. There, a rough approximation of the kind of risk space shown in Figure 1 can be seen through the specifications of 'secured events' and associated outcomes that the system operator should prevent from happening. The set of secured events includes single and double circuit fault outages, loss of 'infeed' (i.e. power being injected onto the system), loss of 'outfeed' (i.e. power being taken from the system) and fault outages of busbar sections.

For all types of secured events, 'unacceptable frequency conditions', 'system instability' and 'Unacceptable Sub-Synchronous Oscillations' are to be avoided. (See Annex 1 of this report for definitions of terms). However, the idea that relatively modest consequences might be tolerated for the rarest category of secured event can be seen in the amount of demand (or, as it is expressed in the SQSS, 'supply capacity') that might be lost. For example, for double circuit or busbar section fault outages, up to 1500 MW of 'loss of supply capacity' would be regarded as acceptable.

Chapter 5 also notes that, under 'adverse conditions' – defined as "conditions that significantly increase the likelihood of an overhead line fault[4]" – where "there is no significant economic penalty", there should be tighter security against a double circuit fault such that the loss of supply capacity should be no greater than 300 MW. The system operator is also permitted to tighten security, i.e. reduce impacts, "during periods of major system risk", defined as periods in which "secured events are judged to be significantly more likely than under the circumstances addressed by the normal criteria of this Standard, or they are judged to have a significantly greater impact than normal, or events not normally secured against are judged to be significantly more likely than normal such that measures should be taken to mitigate their impact". That is, when probabilities of faults are higher than usual, impacts should be smaller and, by implication, the system operator is permitted to spend money to make them smaller.

The difference between operating criteria and the rules guiding network design is in terms of the background conditions against which security is to be assessed. For system operation, they are the 'prevailing system conditions'. For network design, such as covered in SQSS chapters 2 to 4, they concern the dispatches of generation, the level of demand and whether or not there are planned outages. For some conditions, if specified secured events cannot be secured against, the network's capacity should be increased, i.e. it should be reinforced; for others, the need for network reinforcement depends on a cost-benefit analysis: the value of enhancing network capacity versus the cost of that enhancement.

One of the intentions when the first version of the SQSS was written was to make it clear when the system operator (or network designer) was obliged to do something, compared with when they were not, and when they were entitled to do something (if they judged it to be appropriate). The value of that might be most easily understood when something goes wrong, most particularly when a lot of load is disconnected. There is a societal impact of that. Government, the regulator of the electricity sector – Ofgem – and affected energy users will want to know if the system operator had been doing everything they were supposed to be doing, i.e. were their actions and the pre-disturbance state of the system compliant with the SQSS? Or did what happened fall into the category of 'residual risk'? For significant events, as was the case most recently in GB following the triggering of LFDD on 9 August 2019, Government and/or Ofgem will conduct an enquiry and assess compliance [10][11][12]. That can only be determined if the SQSS is written sufficiently clearly and unambiguously.

2.5 Practical assessment of the impacts of secured events

In general, the SQSS does not specify how impacts are to be assessed or how to prove compliance. A great many uncertainties affect how the system would behave and how its likely behaviour should be assessed. Implicitly, good engineering practice is assumed to be followed, e.g. in addressing uncertainties through the formation of a number of judgements or assumptions on which assessment of compliance with the SQSS depends. These include:

- what is the minimum set of equations that should be solved in order to determine how the system would respond to a particular disturbance;

[4] The examples given in the SQSS are "high winds, lightning, very high or very low ambient temperatures, high precipitation levels, high insulator or atmospheric pollution, flooding".

- whether a particular piece of software, designed to solve the given set of equations, does so reliably;
- what the parameters of the system are (including control and protection);
- in real-time, what is the initial condition of the system; in planning, what set of simulated initial conditions would represent reasonable coverage of the likely spread of possible system conditions;
- whether protection and control – including delivery of frequency containment reserve – would operate reliably or, if not, how often it would fail and in what way.

In order that good judgments can be made by a system operator – in the case of the GB electricity transmission system, NESO – there needs to be sufficient access to measurements and data relating to equipment owned by other parties. One of the intentions of the Grid Code is to ensure that that happens. Continued suitability of the Grid Code and other industry codes such as the SO-TO Code needs to be ensured as technologies change, e.g. the growth in use of inverter-based resources such as wind or solar farms or imports via high voltage direct current (HVDC) links, or regulatory arrangements change, e.g. the separation of network ownership from system operation. These codes need to be updated in a timely manner to enable secure, economic and efficient operation of the system.

How much is spelled out in the text of the SQSS, how much is left to good engineering practice and whether there is a need for any kind of approved guidance document to ensure consistent and correct interpretation and application of the SQSS is a matter for judgment by a regulator.

Much of what is required to assess SQSS compliance has been established over many decades by engineers not just within GB but around the world, e.g. the standard sets of equations and associated solution methods to determine what would be the steady state of the system under a particular set of conditions, how big fault currents would be as a result of short circuits at different locations at different moments in time, and how the system and its main elements would respond over a period of seconds to minutes following some kind of disturbance. Common practice internationally also includes the use of a number of common, commercial software tools used to solve relevant sets of equations, manage input data and show results. This includes DIgSILENT PowerFactory used by NESO and the three onshore transmission owners (TOs) in GB. However, significant challenges remain in ensuring accurate system simulation, not least in correctly representing the behaviours of power electronic inverters and their impacts on voltages and currents across the system and on the performance of network protection. Moreover, in spite of the existence of so much convergence across many countries in power system engineering practice and the use of well-established tools, there is still a need for considerable expertise on the part of users of those tools. Users need to know how to set up system parameters, initial conditions and events, and how to interpret results, including knowing the tools' limitations and having a strong sense of when not to believe a certain set of results. All of that comes not just from education and training but also from experience.

The last of the set of factors listed at the start of this subsection concerns how the system itself responds to an initial event. Many parts of the SQSS make clear that assessment should take account of them. These include the following:

- Definition of steady state: "A condition of a power system in which all automatic and manual corrective actions have taken place and all of the operating quantities that characterise it can be considered constant for the purpose of analysis."

- Definition of corrective action: "Manual and automatic action taken after an outage or switching action to assist recovery of satisfactory system conditions; for example, tap changing or switching of plant."
- Paragraph 6.8 and the reference to load response: "The voltage step change limits must be applied with load response taken into account".
- Definition of loss of power infeed: "re-distribution should be taken into account in determining the total generation capacity that is disconnected. However, in assessing this re-distribution, consequential losses of infeed that might occur in the re-distribution timescales due to wider generation instability or tripping, including losses at distribution voltage levels, should be taken into account".
- Definition of transient time-phase: "The time within which fault clearance or initial system switching, the transient decay and recovery, auto switching schemes, generator inter-tripping, and fast, automatic responses of controls such as generator Automatic Voltage Regulation (AVR) and Static VAR Compensation (SVC) take place. Load response may be assumed to have taken place. Typically 0 to 5 seconds after an initiating event".

The term 'steady state' is used in the SQSS in connection with unacceptable voltages and unacceptable frequency conditions. The reference in the definition of steady state to corrective actions makes clear that assessment of SQSS compliance must include consideration of all consequences of an initial secured event. Practical simulation of events makes that difficult. One common simplification in respect of the potential for overloads or unacceptable voltages is to assume that the system will reach an electro-mechanical equilibrium and to solve only the algebraic equations describing a new steady state, i.e. neglecting differential equations. That is, a 'load flow' (also known as a 'power flow') analysis will be carried out. However, even in this, certain automatic system responses can and should be modelled. These include actions of generator, synchronous compensator, SVC and static compensator (STATCOM) automatic voltage regulators; automatic switching of capacitor banks; automatic voltage control on on-load tap-changing transformers; automatic switching schemes such as inter-trips; and, insofar as it can be modelled via a 'distributed slack bus', utilisation of frequency containment reserve.

Where dynamic responses need to be understood more precisely, dynamic simulations should be carried out. However, again, certain simplifications might be adopted to speed up a simulation or reduce the number of parameters and values of independent variables to be defined. These include whether or not to assume that voltages and currents can be adequately represented by 'phasors' (in so-called 'RMS simulation' as distinct from the more detailed and much more computationally demanding 'EMT simulation'), and what level of network and spatial detail is required, from a 'single bus' model used to give a first approximation of system frequency through to a representation of the GB network comprising 1000 or more nodes[5].

Decisions on what kind of modelling would suffice in order to be confident of compliance with the SQSS depends on knowledge, experience and judgment. A load flow analysis is a basic first step. Where unacceptable frequency conditions or system instability are judged to be possible as a result of a secured event, that event should be assessed in a dynamic simulation, albeit there are still some uncertainties, e.g. on the type and precise location of a short circuit fault and how protection can be assumed to respond. Here, the SQSS offers some direction: "in NGET's transmission system and on other circuits identified by

[5] The PowerFactory software used by GB electricity transmission licensees includes load flow, short circuit current estimation and RMS simulation capability.

agreement between the relevant licensees, clearance times consistent with the fault location together with the worst single failure in the main protection system should be used".

In spite of the occurrence of hundreds of unplanned outages on the transmission system every year and the complexities of assessing their impact, there have been very few major loss of load events. Although major losses of demand do occur somewhere in the world from time to time, the industry globally and in GB in particular has been very successful at ensuring reliable supply of electricity from the transmission system. That is, established industry practices have been very successful at limiting risk.

That success comes at a cost that includes the costs of balancing services, the development and maintenance of network infrastructure, and network users' compliance with the Grid Code and, for distribution network users, relevant Engineering Recommendations. However, it does mean that society in GB can be very confident that our needs for electricity will be met.

3 Frequency containment and the Security and Quality of Supply Standard (SQSS)

3.1 What the SQSS says

There are a number of elements that, since the first version of the England and Wales SQSS was adopted in 1999, have guided how a transmission network designer and a system operator should manage system frequency.

1. Design of a network connection for a generator such that, under defined generator dispatch conditions, defined secured events would not lead to a loss of power infeed exceeding either the ‘Normal Infeed Loss Risk’ or the ‘Infrequent Infeed Loss Risk’, depending on the secured event.
2. Operation of the system such that a defined secured event would not lead to frequency conditions deemed unacceptable.
3. The definitions of sets of secured events, ‘Normal Infeed Loss Risk’, ‘Infrequent Infeed Loss Risk’ and ‘Unacceptably High or Low Frequency Conditions’ or ‘Unacceptable Frequency Conditions’.

Various revisions to the SQSS have been made over time. When the wholesale electricity market in Scotland was merged with that in England and Wales and National Grid was designated as the single transmission system operator for GB in 2005, a GB SQSS was introduced.

In version 1.0 of the GB SQSS, the criteria for design of the connection of a generator were given in chapter 2, and for operation of the system in chapter 5. The definitions shown in Table 1 in Annex 1 of this report were used. (At the time, NGC – National Grid Company – was the transmission owner for England and Wales and system operator for GB).

At the time of writing this report, version 2.10 of the National Electricity Transmission System (NETS) SQSS defines those terms as shown in

Table 2 in Annex 1.

The events to be secured against are defined in chapter 5 of version 2.10 of the National Electricity Transmission System (NETS) SQSS as follows [1].

5.1 The *onshore transmission system* shall be operated under *prevailing system conditions* so that for the *secured event* of a *fault outage* on the *onshore transmission system* of any of the following:

5.1.1 a single *transmission circuit*, a reactive compensator or other reactive power provider; or

5.1.2 a single *generation circuit*, a single *generating unit* (or several *generating units* sharing a common circuit breaker), a single *power park module*, or a single *DC converter*; or

5.1.3 the most onerous *loss of power infeed*; or

5.1.4 the most onerous loss of power outfeed; or

5.1.5 where the system is designed to be secure against a *fault outage* of a section of *busbar* or mesh corner under *planned outage* conditions, a section of *busbar* or mesh corner,

there shall not be any of the following:

5.1.6 a *loss of supply capacity* except as specified in Table 5.1

5.1.7 unacceptable frequency conditions;

5.1.8 unacceptable overloading of any primary transmission equipment;

5.1.9 unacceptable voltage conditions;

5.1.10 *system instability; or*

5.1.11 *Unacceptable Sub-Synchronous Oscillations*

In addition, paragraph 5.3 reads as follows:

5.3 The *onshore transmission system* shall be operated under *prevailing system conditions* so that for the *secured event* on the *onshore transmission system* of a *fault outage* of:

5.3.1 a *double circuit overhead line*; or

5.3.2 a section of *busbar* or mesh corner,

there shall not be any of the following:

5.3.3 a *loss of supply capacity* greater than 1500 MW;

5.3.4 *unacceptable frequency conditions*;

5.3.5 *unacceptable voltage conditions* affecting one or more *Grid Supply Points* for which the total *group demand* is greater than 1500 MW;

5.3.6 *system instability* of one or more *generating units* connected to the *supergrid; or*

5.3.7 *Unacceptable Sub-Synchronous Oscillations.*

However, paragraph 5.8 reads as follows:

> 5.8 The *ISOP* shall use the latest version of the *Frequency Risk and Control Report* as consulted on and approved by the *Authority* to determine the events for which *unacceptable frequency conditions* shall not occur. *The Frequency Risk and Control Report* assessment includes consideration of any consequential loss of distributed energy resources associated with any such event.

On the face of it, there would appear to be two definitions of the events for which unacceptable frequency conditions should be avoided:

1. those in paragraph 5.1 plus those in paragraph 5.3;
2. those in paragraph 5.8.

However, paragraph 5.11 is as follows:

> Exceptions to the criteria in paragraphs 5.1 to 5.7 and 5.9 may be required … in relation to 5.1.7 and 5.3.4 only, based on the outcome of an assessment conducted in accordance with the *Frequency Risk and Control Report.*

To be unambiguous, the Frequency Risk and Control Report (FRCR) referred to in paragraphs 5.8 and 5.11 needs to be very clear on whether exceptions actually are required, under what conditions and for what events frequency is to be kept within defined limits.

- Is the requirement of paragraph 5.8 of the SQSS in addition to or instead of what is in paragraphs 5.1 and 5.3?
- Is it actually required that what is specified in the FRCR replaces what is in paragraphs 5.1.7 and 5.3.4 of the SQSS?
- Is what is written in the FRCR clear about the events for which unacceptable frequency conditions shall not occur?

3.2 What FRCR is trying to do

If a secured event would lead to unacceptable frequency conditions in system operation, the SQSS obliges the system operator to take action. In broad terms, the following options are generally available:

1. procure more frequency containment reserve;
2. increase system inertia so that more 'inertial response' – use of kinetic energy stored in rotating mass on the system in response to imbalance between total system infeed and outfeed plus network losses – is available;
3. re-dispatch the largest infeeds or outfeeds such that the size of power imbalance resulting from their loss is reduced.

These are the potential actions that are addressed by FRCR 2025[6].

All the above actions incur a cost; the cheapest action should be taken. However, an action might be paid for to protect against an event that might not happen. The FRCR attempts to answer the question: given the costs of actions to contain the frequency deviations arising from different unplanned system events and the risks associated with those events, which events are worth securing against, and what should be the associated limits to impacts? It also tries to give guidance on the first two of the three actions listed above: procurement of

[6] See section 5 of the Methodology Report [13].

frequency containment, specifically Dynamic Containment (DC); and procurement of system inertia.

The definition of the FRCR in the SQSS says the following:

> The report shall include an assessment of the magnitude, duration and likelihood of transient frequency deviations, forecast impact and the cost of securing the system and confirm which risks will or will not be secured operationally by the *ISOP* in accordance with paragraphs 5.8, 5.11.2, 9.2 and 9.4.2.

The FRCR Methodology [13] presents an approach to an explicit assessment of the costs and benefits of different levels of risk in respect of management of system frequency. It includes costs of actions and probabilities of impacts. However, it does not include any way of judging what is an acceptable probability in respect of different impacts.

The SQSS and Grid Code have specifications of how low frequency can be allowed to go:

- the usual statutory limit – 49.5 Hz;
- the frequency at which the first stage of LFDD is triggered – 48.8 Hz.

What the author of this report understands to be operational practice also stipulates that system frequency can fall by 0.8 Hz – from the nominal frequency of 50.0 Hz, this would mean falling as low as 49.2 Hz – with a return to more than 49.5 Hz within 60 seconds. (See an undated published document with no designated owner or author entitled “Frequency Response Obligations Statutory, Code and Operational Standards” [14]).

Given variations in measurement and relay action for LFDD, there might also be interest in the likelihood of system frequency falling as low as, say, 49.0 Hz, in order to leave some margin before triggering of LFDD.

In light of those definitions, the key question to be answered in respect of management of risk of low frequency concerns conditional probabilities:

- Given that the system is initially at a certain frequency f, system inertia is initially H and the Dynamic Containment headroom (the margin by which total infeed can be increased or outfeed decreased) is D and is fully delivered, what is the probability that the frequency nadir is:
  i) less than 49.5 but above 49.2 Hz and returns within 60 seconds;
  ii) less than 49.5 but above 49.2 Hz and does not return within 60 seconds;
  iii) less than 49.2 Hz but above 49.0 Hz;
  iv) less than 49.0 Hz but above 48.8 Hz;
  v) less than 48.8 Hz.

Variables H and D are quantities that NESO can usually control, albeit at a cost in respect of Balancing Mechanism, ‘pre-gate’ or ancillary service actions.

- If total system inertia (which includes contributions from synchronous condensers and from loads) as determined by the market’s decentralised dispatch of generation is not already at minimum certain level, H_{min}, there is usually enough appropriate plant available that would enable NESO to re-dispatch generation such that total system inertia is at least at that certain level.
- To date, enough Dynamic Containment reserve has usually been available to enable NESO to procure at least a chosen amount of such reserve, D_{min}.

(Exceptions might be when certain key assets have experienced forced outages).

The core questions of policy addressed by FRCR are: what should the values of H_{min} and D_{min} be given an intention to limit the probabilities of different values of frequency nadir being reached following disturbances to the system?

Based on history or modelling of future generation and demand backgrounds, estimates can be made of the probability of system inertia being at different levels (including the effect of any NESO re-dispatch actions), and the probability of system frequency initially being at different levels. In respect of the latter, NESO has chosen for the FRCR work to assume that f is initially always 49.85 Hz, a level that, according to the FRCR team[7], the system was above for 99.4% of the time between January and November 2025.

In principle, estimates can also be made of the probabilities of losses of infeed or low voltage induced frequency deviations due to different disturbances. These are affected by what is on the system and by combinations of independent events.

The sorts of disturbances that can affect system frequency include:

1. 'infeed side' losses of infeed, i.e. where there is an outage of a source of power, caused by an event within or on the input of power to that source, whether a power station, wind farm, an interconnector that it is importing power into GB or an energy storage facility that is discharging;
2. 'outfeed side' losses of outfeed, i.e. an outage of a power sink, e.g. an exporting interconnector, a storage facility that is charging or an energy user's load.
3. 'network side' events such as disconnections of infeed or outfeeds caused by unplanned network outages. These might involve fault current ('active faults'), detected and interrupted by network protection, or disconnections caused by maloperation of protection or manual action by a system or network operator (sometimes called 'passive faults'), most likely for reasons of safety.

It is possible that a loss of infeed or outfeed might trigger another loss, exacerbating the impact on system frequency. Experience suggests that that is unlikely but, if it is going to happen, it will probably be due to responses to a voltage dip caused by a short circuit fault on the network, i.e. a failure to 'ride through' the fault, or the action of 'loss of mains' protection of generation or storage connected to a distribution network. Requirements in the Grid Code section CC.6.3.15 [7] set out the conditions under which sources of power should continue to operate and ride through a network fault. Engineering Recommendations G59 and G99 set out the parameters of loss of mains protection [15][16]. System conditions might arise under which these documents permit a trip of generation or an energy store. However, incorrect settings or measurement or control error might lead to a trip. The GB system frequency disturbance that happened on 9 August 2019 is an example of an event in which a large number of consequential trips of generation happened in a short space of time, leading to the triggering of Low Frequency Demand Disconnection when system frequency fell to 48.8 Hz. (See, for example [12]).

It is also possible that random, independent losses of infeed or outfeed can happen within a such a short space of time that the system operator is unable to correct the system for the impact of one event before the next one happens.

The number of different system conditions and combinations of different possible events makes it extremely challenging to derive a set of probabilities and to simulate each of the

[7] Email to Keith Bell from NESO, 9 January 2026

very large number of possible disturbances. It is therefore necessary to make conservative or simplifying assumptions. For example:

- Similar initial conditions might be clustered together and single representative cases simulated from each cluster.
- Certain, perhaps conservative, values might be assumed for how much infeed from distribution connected resources (generation and discharging storage) might be lost due to action of loss of mains protection (ROCOF-based or vector shift-based).
- Infeed losses that are consequential to an initial loss, or random, independent losses that occur before the system has been re-secured[8], are treated as happening simultaneously.

It appears from the FRCR Methodology Report that NESO has used simplifications such as those outlined above. Their appropriateness is discussed in the next section.

[8] It may be interesting to note that the SQSS includes the concept of a 'major system fault', defined as "An event or sequence of events so fast that it is not practically possible to re-secure the system between each one, more onerous than those included in the normal set of *secured events*."

4 The quality of evidence provided by NESO in support of its proposals

The FRCR advice is based on:

a) simulations of the impacts of different events;
b) estimates of probabilities of those events;
c) an appraisal of the costs of procuring certain amounts of system inertia and certain amounts of Dynamic Containment.

Analysts carrying out assessments to inform the advice depend on access to appropriate simulation tools and data describing past events, likelihoods of future events and the costs of different actions.

Stakeholder support for the advice given rests of the quality of evidence published by NESO. The following three subsections discuss each of the above elements.

4.1 Simulations of the impacts of different events

It would normally be expected that information on the nature of the model used to simulate events and their impacts is provided in reports the conclusions of which depend on results from those models. Evidence of validation of the models would also be expected.

Little information is provided in the FRCR 2025 Report [3] and associated Methodology report and Data Handbook [13][17] on how events and their impacts are simulated in order to determine the outcomes that would arise. The main evidence provided on the accuracy of modelling appears to be in section 9 of the main FRCR report in the chart showing simulations of three frequency disturbances with the frequency recorded in the event compared with a simulation of what happened with the level of inertia present at the time and what would have happened were the inertia to have been at 120 GVA.s or 102 GVA.s. The three events are:

1. what happened on 14 March 2025 when the level of inertia present at the time was 276.4 GVA.s;
2. what happened on 12 December 2025 when the level of inertia present at the time was 172 GVA.s; and
3. what happened on 9 August 2025 when the level of inertia present at the time was 210 GVA.s.

The simulation of the 14 March 2025 event with 276.4 GVA.s of inertia is shown to have a close match with the recorded frequency albeit with a slightly better frequency recovery in the simulation after around 12 seconds after the disturbance.

The simulation of the 12 December 2025 event with 172 GVA.s is shown to have quite a close match with the recorded frequency albeit that the simulation shows a slightly lower frequency nadir after the first disturbance and a better recovery in the first few seconds after the second nadir. The actual frequency recovered from around 65 seconds after the initial event whereas the simulated one did not. A reader of the FRCR report is left to assume that use of frequency restoration reserve was not simulated.

The event on 9 August 2019 was quite complex involving losses of two Balancing Mechanism Units (BMUs) due to failure to ride-through a voltage dip caused by a transient short-circuit fault on a single overhead line, plus trips of distributed generation due, it is supposed, to action of loss of mains protection. One simulation, described as “Confirmed loss under 210 GVA.s (Pre-ALoMCP[9] with the actual inertia of 210 GVA.s)", would seem to come closest to an attempt to simulate what actually happened using the same modelling approach as used in the FRCR work. The rate of change of frequency (ROCOF) in that simulation up to the first frequency nadir appears to be higher than that in the actual event but the nadir is much lower. It is not completely clear from the FRCR report why that should be although it is noted that "In the simulations, response holdings are assumed to align with the current frequency control policy, i.e. FRCR 2024." 'Current frequency control policy' relates to the holding of Dynamic Regulation, Dynamic Moderation and Dynamic Response ancillary services.

In a discussion with the authors of the FRCR report, it became apparent to the author of this review that a bespoke, 'single bus' model, built and run in dedicated code (rather than in, for example, PowerFactory) is being used for FRCR work. This means that only variations to frequency of the system's 'centre of inertia' would be apparent, something that is difficult to define precisely. In practice, voltage angles are different at every location on the system and, following a disturbance, they change at different rates. Thus, as 'system frequency' can be observed as the rate at which the instantaneous voltage goes through a complete cycle, the system frequency – and the rate of change of frequency (ROCOF) – apparent at each location is different. This can lead to controls or protection based on local measurements of frequency or ROCOF responding to an event in different ways depending on location. This includes loss of mains protection on distributed resources and relays for Low Frequency Demand Disconnection (LFDD) where, for the same event, relays can be triggered in one region but not in another.

If the main aim of frequency containment is to avoid disconnection of demand, use of a single bus model might, in principle, mean that risk cannot be fully understood. However, this does not mean that single bus models are without value – they are much easier and faster to run than a dynamic simulation of every substation and the plant connected to them. They can represent a useful 'first pass' assessment of frequency control and are especially useful in evaluation and optimisation of a range of control options.

In order to be confident that risks are being well-managed even when using a single bus model, suitable 'proxies' should be used in the model to represent effects that cannot be directly represented in that model[10]. It is usually prudent to set the parameters of these proxies conservatively. Ideally, those choices would be informed by more detailed modelling (that only needs to be done periodically) or by a sufficiently large set of observations from the power system itself. Those observations depend on adequate spatial coverage by suitable metering, e.g. phasor measurement units (PMUs). My understanding is that a number of PMUs were installed in Scotland 10 or more years ago but there are very few in England and Wales. However, I also understand that NESO has access to data from around 40 "XMU" devices owned by Reactive Technologies and installed across GB[11].

As is discussed further in sections 4.2 and 7.2 below, broadly speaking, the approach described above is the one that NESO has taken. Provided good choices are made on model parameters, it is reasonable. One of those parameters is how much Dynamic Containment reserve is available. This service now appears to be very effective. Evidence of how much is procured and how much is successfully delivered in response to each

[9] ALoMCP is the Accelerated Loss of Mains Change Programme
[10] This is true of any model for any purpose.
[11] I have not found a published definition of what an XMU does or how it differs from a PMU. I also do not know the commercial terms under which NESO has access to the XMU data and whether such access can be relied on in future. For some discussion of XMUs, see [26].

frequency event would help give confidence to stakeholders that there is less need for system inertia than there seemed to be in the past.

Another important parameter is demand side inertia. The FRCR 2025 Data Handbook says this is “estimated by a demand inertia factor that is derived based on historic frequency events” [17]. It is not clear how many events are used. It also appears that a single factor is used for all operational conditions in the modelling. Given the daily, weekly and seasonal variations not just in demand but in the nature of demand, i.e. what electrical energy is used for, and the fact that the net demand observed by NESO is a function of how much DG of different types is operating, something that depends on time of day, season and weather conditions, the inertia of net demand is unlikely to be a constant value. However, a conservatively low value could be chosen for use in system modelling, provided there is evidence to support that choice.

How much demand side inertia varies should be investigated with tests of the sensitivity of system behaviour to changes in demand side inertia. Ideally, NESO would have a clear idea what part of net demand is distributed generation (including storage that is discharging) and how much is end use of electricity. That would help explain both variations in demand and potential variations in demand side inertia. Importantly, it would contribute to understanding the extent of exposure in different parts of the network to operation of DG loss of mains protection under different conditions. However, my understanding is that total net demand is based on an estimate: metered output of transmission connected generation less an estimate of transmission network losses (with, potentially, some correction depending on whether system frequency is rising or falling at the time). By contrast, access to power flow metering – or the results of a system state estimation – at each grid supply point would give net demand by location.

4.2 Estimates of probabilities of loss of infeed events of different magnitudes

As discussed in section 3.2 above, the sorts of disturbances that can affect system frequency include:

1. ‘infeed side’ losses of infeed;
2. ‘outfeed side’ losses of outfeed; and
3. ‘network side’ events such as disconnections of infeed or outfeeds caused by unplanned network outages, potentially involving fault current.

The FRCR Methodology lists the following event types in section 8.2.1 [13]:

- “BMU-only” events;
- “BMU+VS” events;
- “Simultaneous events".

The description given for the first of these leads the author of the present review to liken them to ‘infeed side’ and ‘outfeed side’ events in that they do not involve unplanned outages of network assets. On the other hand, a BMU+VS event is described in the Methodology report as being “initiated by transmission fault”. Thus, it is a ‘network side’ event.

As noted in section 4.1.1 of the Methodology Report:

- “BMU-only” events might involve loss of distributed energy resources (DER) due to operation of ROCOF related loss of mains protection on DER. However, it is assumed that impacts on voltage angles and magnitudes are small enough to not trigger vector-shift related loss of mains protection.

- "BMU+VS" events: although only vector shift protection is noted in the name, the Methodology report states that ROCOF protection might also be triggered.
- "Simultaneous events". This is "an event that disconnects two BMUs at the same instant and may or may not also cause a consequential RoCoF loss". It is also described as being "made up of BMU-only events".

For "BMU-only" events, the Data Handbook says that probabilities of loss are based on change in "Maximum Export Limit (MEL) between 4-hour ahead and real time" with each change apparently considered to be a breakdown or unplanned outage [17]. If this is so, the estimate of BMU failure rates for the purpose of assessing the system frequency impacts of a loss of infeed would be conservative as a 4-hour ahead change in MEL might only reflect a planned ramp down in output; or might be for a unit that was initially off, was planned to come on and then, in a revised plan, not planned to come on. The ramping case would represent a much more modest loss of infeed event than if the unit had been running at full output and then tripped; failure to come on would not be a loss of infeed. The net result would be an over-estimate of system frequency related risk. From subsequent discussions with NESO's FRCR team, I understand that all instances of a BMU's output changing from non-zero to zero are noted with a check of the BMU's MEL value from 4 hours before each instance in order to determine whether the reduction to zero was planned or unplanned.

One consultation respondent drew attention to the following in NESO's FRCR Data Handbook: "Multiple breakdowns within 24 hours is treated as one failure, as the unit is likely to be struggling to return". Actually, if the unit has resynchronised and then tripped, that would be a distinct loss of infeed event that would disturb system frequency and would do so each time it happened.

It may also be noted that, although the BMU data are, in principle, available from Elexon's website, they have not been published in the Data Handbook.

It is asserted by NESO in the FRCR work that "VS-only and VS+RoCoF risks are fully mitigated post the Accelerated Loss of Main Change Programme (ALoMCP)." From discussion with NESO's FRCR team, I understand that "fully mitigated" means that enough Dynamic Containment reserve is held in order to limit the system frequency nadir on the assumption that a certain amount of DG will indeed trip as a result of operation of VS protection. Review of the suite of FRCR documents suggests that there is significant uncertainty on how much DG there is of different types – and with different loss of mains protection settings – connected to the distribution networks connected at each grid supply point.

The probabilities of "BMU+VS" events – each "initiated by transmission fault" – are based on the likelihoods of connections between generators and the main transmission network being interrupted. For a single circuit connection, this can happen with the loss of only one circuit; for a two circuit connection, both circuits need to be lost. Although it is possible for connections comprising 3, 4 or more circuits to be lost, the Methodology, not unreasonably, neglects these failure modes on the grounds that it would be extremely rare for them to occur. Instead, the following are used: the probabilities of single circuit fault outages on single circuit connections; of double circuit fault outages on double circuit connections where both circuits are initially in service; and single fault outages on double circuit connections where one circuit is initially out of service. The probabilities of fault outages are based on overhead line fault rates and the lengths of overhead lines; and on rates of occurrence of bus section faults. Losses of connection to offshore wind farms where the connection would comprise a section of subsea cable on each circuit are also considered. This approach seems reasonable and is worked out for each BMU. It seems, from section 5.2.3 of the Data Handbook, that the amount of distributed generation (DG) disconnected due to action of vector shift protection is some function of the amount of DG in the vicinity of the BMU under consideration. However, it is not clear from the Data Handbook what these amounts are.

“Simultaneous events” merit some discussion. The Methodology report notes, entirely reasonably, that “modelling simultaneous event is inherently challenging due to the complex nature of these events as well as its limited occurrence” meaning that there are insufficient data to allow confidence to be built in their probability of occurrence.

The description in the Methodology Report implies that only ‘infeed side’ events are being considered. This is in spite of the most high profile frequency event of recent years – that on 9 August 2019 – being a network fault for which two BMUs failed to ride-through. That is, they were not completely independent infeed losses – they were both triggered by the same network fault. Failure to ride through a network-side event offers an explanation potentially for many “simultaneous” or near-simultaneous losses of multiple infeeds.

It seems that the approach taken is to consider the potential for two BMU units to trip within a short space of time and, when modelling them, to make the conservative assumption that they trip simultaneously. From discussion with NESO’s FRCR team, I understand that probabilities are based on 6 years of data and the occurrence in that time of two or more BMUs tripping within 10 minutes of each other. This is further discussed in section 6.1 below.

4.3 Appraisal of costs

The main costs of potential actions to manage system frequency are those of:

1. holding and utilisation of Dynamic Regulation, Dynamic Moderation, Dynamic Containment and Static Firm Frequency Response;
2. re-dispatching infeeds to achieve a certain level of system inertia;
3. re-dispatching infeeds to reduce the size of a loss of infeed event.

The third of the above seems not to have been considered in the FRCR 2025. Given the apparently low cost of procuring Dynamic Containment as an alternative to that action, that is not unreasonable.

Additional inertia in each half-hour settlement period is presented as being acquired via constraining-on CCGTs to a ‘stable export limit’ (SEL) of 250 MW at a cost of £112.5/MWh for the constrained-on ‘Offer’ action plus £42.50 for a ‘Bid’ to reduce output from a wind farm.

The broad approach seems reasonable.

5 Other issues raised by consultation respondents

A number of matters were raised by respondents to either NESO's[12] or Ofgem's[13] consultations on FRCR 2025 that are worthy of some attention beyond any responses given by NESO. They are discussed in this section.

5.1 Risks not addressed in the FRCR 2025 report

A number of respondents noted that NESO's assessment of frequency containment risk does not take into account the potential, following a disturbance, for local variations in system frequency to trigger ROCOF-based loss of mains protection or LFDD in a particular region, or for voltage dips to trigger vector shift-based protection. This issue is discussed in section 4 above.

One respondent noted the potential for outfeed-related events to disturb system frequency in a significant way, in particular:

- large step changes to net demand seen on the transmission system due to electrical loads switching on or off as many 'smart' controls of flexible demand such as electric vehicle charging or electric heating align with changes to the real-time electricity price;
- large loads being tripped due either to network faults or 'outfeed side' faults. Interconnectors that are in an exporting condition already have the potential to create a large loss of outfeed disturbance. Many data centres are already connected to the GB power system and are large consumers of electrical energy.

While the first of the above issues is, as I understand it, already apparent in frequency traces, it is not yet large enough to drive the need for significant additional frequency containment reserve. Similarly, data centres are not yet large enough to represent a significant problem for management of GB system frequency although mooted new centres are growing ever larger. However, in the event of a network fault causing disconnection, data centres' use of on-site back-up generation means that, once a network connection has been made available again, timing of return of data centre load to the network is uncertain.

In respect of exporting interconnectors and loss of outfeed, my understanding is that the FRCR work already models them.

A number of respondents noted that the GB system – as other systems have – has seen a number of instances of sub-synchronous oscillations (SSO) in recent years, seemingly due to control system interactions. These respondents asked whether these might trigger losses of infeed (or outfeed). Some have suggested that the likelihood of SSO occurring is reduced when system inertia is high.

NESO has acknowledged that SSO as potential mechanism for causing loss of infeed or outfeed has not been addressed in FRCR 2025. I am not aware of many instances of SSO-related trips. Also, my understanding is that there is no strong relationship between occurrence of SSO and system inertia. However, I would agree that risks associated with SSO and ways of mitigating them need to be addressed.

[12] See https://www.neso.energy/industry-information/codes/security-and-quality-supply-standard-sqss/frequency-risk-and-control-report-frcr
[13] See https://www.ofgem.gov.uk/publications/frequency-risk-and-control-report-2025

One respondent raised a concern that temporary overvoltage could lead to generators tripping. Short-lived rises in voltage on the transmission network could occur for any number of reasons, including regular network switching. While temporary and quite localised, they could, in principle, lead to generators – or interconnectors, energy storage or large loads – tripping. As the proposal document for Grid Code modification, GC0178, raised by NESO, says, “The Grid Code does not include specific limits on temporary overvoltage. It also does not explicitly specify requirements on how generation would respond to a temporary overvoltage” [29]. GC0178 proposes to “Introduce a limit, both in terms of magnitude and duration, on temporary overvoltage following secured events”. It goes on to say, “This limit would need to be maintained by TOs in design timescales and by NESO in operational timescales.” The modification would need to “Clarify the requirements on how plant need to perform during temporary overvoltage in terms of reactive support, ride through, and otherwise.” However, the proposal does not say how often losses of either infeeds or outfeeds occur as a consequence of temporary overvoltage.

The same respondent drew attention to the potential for large, rapid weather dependent ramps of generation that would raise the need for well coordinated counter-balancing actions and, potentially, increase the need for frequency management services. They also noted the potential for similar or even steeper ramps due to rules around negative wholesale market pricing for newer renewable generators in receipt of government-backed contracts for difference which would lead to such generators self-dispatching to zero output in settlement periods in which such rules would take effect.

One respondent raised the idea of defining, in the SQSS, an “insufficient frequency containment margin” as a prompt to action to decrease the frequency deviation that would result from a disturbance. This idea is worthy of investigation.

5.2 Frequency containment measures not modelled in FRCR 2025

One consultation respondent noted the following:

> “We discussed with NESO the potential for Low Frequency Sensitivity Mode – Under frequency (LFSM-U) to be deployed across assets such as batteries and interconnectors. This would provide an additional layer of frequency containment ahead of Low Frequency Demand Disconnection for exceptional events at a lower inertia level.”

NESO has apparently noted LFSM-U as being available within existing available headroom of normal operation. It would be useful to see it taken into account in system modelling although the likely delivery of LFSM-U may be hard to quantify as, according to what I have been told by NESO’s FRCR team, an obligation to provide it applies only to BMUs that connected in or after 2019. However, such a distinction is not clear to me from what is written in section ECC.6.3.7.2 of the Grid Code.

5.3 Provision of correct information to NESO and sector stakeholders in general

Two Grid Code modifications were raised with a view to improving the information available to stakeholders on the impacts of faults on or disturbances to the system: GC0105 [18] and G0151 [19]. These were subsequently approved. A further modification has been proposed – GC0181 [20] – in order to improve compliance with those original modifications. A look at a sample of GC0105 and GC0151 reports suggests to me that the information being provided is insufficient to comply with the original intentions. This entails a risk of not building the confidence among stakeholders that NESO is successful in limiting system risk to acceptable levels.

One respondent to the FRCR 2025 consultations highlighted that there is an incorrect polarity on data NESO's energy management system receives from 2.8% of power flow meters on the transmission network. (Half of the meters with incorrect polarity are seemingly owned by offshore transmission owners). While such bad data ought to be picked up by NESO's state estimation process – this is presumably where the 2.8% of meters have been identified – and could, in principle, be corrected by a software fix as they are apparently systematic and known about, correction of the data sent to NESO is the subject of a proposed Grid Code modification, GC0182 [30]. It is not clear to me exactly what the impact of these particular bad data has been although any incorrect estimation of system state might lead to more money being spent on balancing actions than necessary – including those for management of system frequency – or unwitting non-compliance with the SQSS.

5.4 Other concerns

Two respondents queried the value of the independent review of FRCR 2025 commissioned by NESO from Accenture. The review only addressed whether NESO had followed its own processes. It did not question whether the processes and data used were reasonable in order to allow system risks associated with frequency deviations to be managed in a satisfactory way. Without such a review by a suitably qualified party, stakeholders' confidence in the FRCR concept and the position it arrives at will be entirely dependent on the information that is published by NESO. In my view, the Accenture review adds little value.

Some respondents wondered about the effectiveness of the SQSS Panel. One noted, "Following NESO's industry consultation, the SQSS Panel voted by majority in favour of NESO's FRCR 2025 policy recommendations. However, it is important to note that this majority (4) was 'offset' by (3) abstentions." I agree with the respondent's point that this does not represent the ringing endorsement of the FRCR 2025 by the SQSS Panel that a vote of 4-0 might suggest. Another respondent said, "we believe that panel members should engage with independent organisations, and be provided with sufficient funding to undertake that activity".

My understanding is that some concerns about FRCR 2025 were raised by the SQSS Panel, similar to some of those discussed in this report. It would be disappointing if a member of the Panel who has good engineering understanding and has concerns about a proposal being presented to it chooses to abstain rather than vote against. If they do not have good engineering understanding, one has to wonder why they are a member of the Panel.

6 Other issues

6.1 What is a 'simultaneous event'?

One of the challenges in managing risk in any system is knowing how to treat the potential for rare events to have a very large impact: they might not happen but they are conceivable and, if they happen, they could be very damaging indeed. In their FRCR work, NESO has noted that frequency disturbances involving loss of infeed from more than one connected source of power have happened within such a short space of time that the system operator has had insufficient time to resecure the system in between the separate losses. From that perspective, they are simultaneous events. As discussed in section 4.2, the occurrence of 'simultaneous events' is rare enough for it to be impossible to have high confidence in the probability of occurrence of such events of different magnitudes.

One approach that might be taken is to assume that each event within a single 'simultaneous event' is independent of the other. The probability of the combination would then be the product of the probabilities of the individual events. Usually, this would give a very low probability of the combination. However, it is also possible that the individual events are not independent of each other. That is, they are correlated due to there being some connection between them. This might be a common cause or because an initial event triggers subsequent further events. The mechanism behind that might be uncertain but, if the likelihood of the correlated event is higher than that of a second event happening independently, the probability of the combined event will be higher than that of the separate elements happening independently.

Examples of correlated events include the following.

- High wind speed shutdown of multiple wind turbines. (Given variations of wind speeds across any area, the fall in total GB wind production would take the form of a ramp rather than a large single step; however, it may be big enough to exhaust the available frequency containment reserve).
- A large loss of infeed causing operation of ROCOF-based loss of mains protection on distributed resources.
- A short circuit fault causing multiple infeeds or outfeeds to fail to ride through the low voltage, potentially also causing vector shift-based loss of mains protection to operate.
- A large amount of 'smart', flexible demand switching on or off in response to a common price signal.

Some of the above are discussed in FRCR reports.

Events in the last 20 years that have triggered the operation of LFDD have involved correlated outages. One particular thing that is worthy of particular attention in addressing similar future risks is the extent to which failure of connected resources to ride through a disturbance has been a feature of any past frequency disturbance and what can be done to improve compliance with fault ride-through requirements in the Grid Code and whether those requirements need to be updated. This includes in relation to whether large demand should be subject to requirements relating to ride-through and, in the event of a trip, a managed return to the network.

6.2 What the FRCR requires in respect of SQSS compliance

The following was noted in section 3.1 of this report: "the Frequency Risk and Control Report (FRCR) needs to be very clear on whether exceptions actually are required, under what conditions and for what events frequency is to be kept within defined limits." Further, the following questions were posed:

- Is the requirement of paragraph 5.8 of the SQSS in addition to or instead of what is in paragraphs 5.1 and 5.3?
- Is it actually required that what is specified in the FRCR replaces what is in paragraphs 5.1.7 and 5.3.4 of the SQSS?
- Is what is written in the FRCR clear about the events for which unacceptable frequency conditions shall not occur?

The recommendations from the FRCR 2025 include the following:

- Secure all BMU-only events to keep resulting frequency deviations within 49.2 Hz and 50.5 Hz.
- Do not apply additional controls to secure all BMU+VS and simultaneous events.

The implications of those recommendations appear to the author of the present report to be three-fold.

1. In respect of SQSS paragraphs 5.1.7 and 5.3.4 – the avoidance of unacceptable frequency conditions – an unacceptable frequency is only a condition that is below 49.2 Hz or above 50.5 Hz. That is, were the FRCR recommendations to be accepted, it would be acceptable for system frequency, as a result of a secured event, to be between 49.5 Hz and 49.2 Hz. Contrary to what is implied by current operational practice [14], there is no explicit requirement that, should system frequency fall to below 49.5 Hz, it should be restored to 49.5 Hz or above within 60 seconds.
2. The stipulation to "not apply additional controls to secure all BMU+VS and simultaneous events" means that, although "BMU+VS" events and "simultaneous events" might lead to system frequency going above 50.5 Hz or below 49.2 Hz, the system operator is not required to procure enough frequency containment reserve to prevent such frequency deviations. This would appear to have the effect of requiring an assumption when assessing compliance of a given operating condition (including whatever frequency containment headroom and footroom is on the system) with SQSS paragraphs 5.1.7 and 5.3.4 that:
   a. no distributed generation or discharging batteries will trip as a result of operation of vector shift based loss of mains protection;
   b. all infeeds fully comply with Grid Code requirements on low voltage ride-through[14].
3. The potential for distribution connected infeeds to trip due to operation of ROCOF-based loss of mains protection or for sections of distribution network (and all infeeds and outfeeds connected there) to be disconnected as a direct consequence of a secured event needs to be taken into account when assessing the impact of a secured event.

In practice, I understand from the FRCR team that they always consider the size of a BMU loss of infeed event to be, however much power was being produced by the tripped BMU plus any directly consequential further power loss due to the operation of ROCOF-based loss of mains protection on distributed generation. NESO policy is, so I understand, to carry enough system inertia plus frequency containment reserve to ensure that all possible such

[14] As was discussed in sections 4.2 and 6.1, there have been instances of infeeds failing to ride-through low voltages on the network. It would be useful to know how many there have been and if there are any trends in respect of Grid Code compliance.

"BMU" events would lead to an acceptable frequency condition. The FRCR team believes that carrying that much inertia plus frequency containment reserve would lead to the majority of "BMU+VS" events being secured, i.e. leading to acceptable system frequency (where "BMU+VS" means the loss of a BMU plus any consequential trips of DG due to either vector shift or ROCOF-based LoM protection). However, this was not clear to me from the main FRCR 2025 report. Also, it means that the largest "BMU+VS" events – or "simultaneous events" – could lead to unacceptable frequency conditions.

The FRCR provides clarity on acceptable and unacceptable frequency deviations. Because the FRCR does not spell out that they should not be secured against, the full set of secured events would remain those in paragraphs 5.1.1 to 5.1.5, 5.3.1 and 5.3.2.

The FRCR 2025 requirement to "not apply additional controls to secure all BMU+VS and simultaneous events" needs a bit more thought in respect of the full set of secured events. A short circuit fault on a single circuit, double circuit or busbar section would cause a voltage dip during the fault and a change to voltage angles both during the fault and when the fault is cleared. The voltage dip will reduce the power that can be generated and transmitted. For power park modules, the Grid Code requires that active power generation is restored following voltage recovery only at a certain rate. Depending on the location of the fault, clearance of the fault might disconnect infeed and/or outfeed. All of these factors – along with the kinetic energy stored in synchronous plant and the amount and rate of response of frequency containment reserve – will affect the rate of change both of local frequency and of what might be regarded as the 'system frequency', and the frequency nadir.

To know whether system frequency should be kept above 49.2 Hz – and what would constitute enough system inertia or Dynamic Containment to achieve that, depending on what combination is cheapest – for all secured events given all the above influences on system frequency, clarity is required on the meaning of "BMU+VS" and "simultaneous events". To take an example, consider a short circuit fault on a double circuit connecting a large infeed in a region in which a large amount of power is being produced by inverter-bases resources. The fault might be expected to trigger operation of any vector shift based loss of mains protection in the region; it would also cause disconnection of the infeed on the sending end of the faulted double circuit. In FRCR terms, would that be classed as a single event – the original secured event – or a 'simultaneous event': a network fault and a loss of infeed? The infeed might be one or more separate BMUs. Again, is the disturbance a single event or a 'simultaneous one'[15]? Because vector shift protection trips some DG, would it be classed as "BMU+VS"? The scenario outlined could lead to a significant voltage fall with a consequential impact on system frequency. The SQSS would appear to require the procurement of a sufficient combination of inertia and Dynamic Containment to contain the impact of that event for as long as the system is exposed to it.

In reaching its recommendations, the FRCR 2025 does not appear to me to have addressed such circumstances.

Page 78 of the current version of the SQSS states, under the definition of 'Unacceptable Frequency Conditions':

> Transient frequency deviations outside the limits of 49.5 Hz and 50.5 Hz shall:
>
> - only occur at intervals which ought to reasonably be considered as infrequent.

[15] From discussion with NESO's FRCR team, I understand that this event would be treated as a "BMU+VS" event involving one or more BMUs, dependent on the nature of the disconnection.

- only persist for a duration which ought to reasonably be considered as tolerable; and
- only deviate by a magnitude which ought to reasonably be considered as tolerable.

It also says that:

> "It is not possible to be prescriptive with regard to the type of secured event which could lead to transient frequency deviations since this will depend on the extant frequency response characteristics of the system which the ISOP adjust from time to time to meet the security and quality requirements of this Standard."

What the FRCR fundamentally does is set a policy for procurement of frequency containment, both system inertia and actively controlled frequency containment reserve, most notably Dynamic Containment.

One of the recommendations from FRCR 2025 is that a certain minimum of system inertia should always be ensured. The implication of what is stated in section 4.3 of the main FRCR 2025 report – "we currently see approximately 5000 MW of participation in the dynamic response auctions of which we secure around 2000 MW in each Electricity Forward Agreement (EFA) block" – is that the same amount of Dynamic Containment is procured regardless of prevailing system conditions, i.e. the disturbances to which the system is exposed and the inertia that is already on the system. If that were true, because of the variability of conditions, it is possible that more Dynamic Containment is being procured at certain times than is needed to contain the impact of secured events that might occur at those times. However, as the FRCR report notes, if Dynamic Containment is cheap, it might be a worthwhile investment to procure the extra given the risk reduction it provides. Moreover, from discussion with NESO's FRCR team, I understand that the amount of Dynamic Containment procured is based on the predicted system condition and largest loss. That is, it does vary.

The SQSS definition of 'Unacceptable Frequency Conditions' says this: "The Frequency Risk and Control Report will define what is considered reasonable, infrequent and tolerable for each of these criteria for transient frequency deviations." It is not clear to me that the FRCR does. It does not clearly define what interval ought to reasonably be considered as infrequent, what duration ought to reasonably be considered as tolerable or what magnitude ought to reasonably be considered as tolerable[16].

6.3 High frequency risk

Part of an assessment of system frequency risk should address high frequency. The FRCR uses a conservative, i.e. risk-averse, upper threshold of 50.5 Hz and asserts that the probability of exceeding that level is small. However, it should also address what would happen if that limit were exceeded. 'Limited Frequency Sensitive Mode – Over frequency' (LFSM-O) ought to act to limit the frequency deviation. However, as observed in [21], there is the potential to trigger such significant losses of infeed at a high system frequency, e.g. 52 Hz, that a high frequency event becomes a low frequency one extremely rapidly.

As has been observed elsewhere in this report, there is the potential for 'loss of outfeed' events – whether due to faults on the outfeed side or network side of a connection – to

[16] Definitions are given in section 3.2 of the FRCR Methodology Report [13] of one high frequency impact – "H1" – and three levels of low frequency impact – "L1" to "L3". None of these is explicitly referred to in the main FRCR Report [3].

cause high frequency disturbances. Such risks will require more attention as the nature of electrical loads on the GB system changes.

6.4 Differences between inertial response and actuated fast response

The ‘inertia’ of a synchronous generator refers to the kinetic energy stored in its rotating mass. Provided the machine remains electromagnetically synchronised with the rest of an AC power system, this kinetic energy is released or absorbed as the system slows down or speeds up, i.e. system frequency changes. A slowing down or speeding up is a consequence of, respectively, system demand (including any exports of power plus network losses) exceeding total infeed, or infeed exceeding demand. The rate at which kinetic energy released or absorbed – the ‘inertial response’ in terms of power, measured in MW – is proportional to the rate of change of system frequency. It opposes that change and acts to slow it down. However, any store of energy would suffice to slow down a change in system frequency or, indeed, to correct imbalances between infeed and demand. System frequency can be kept within acceptable limits if the correction is sufficiently large and can be delivered quickly enough.

System modelling and, increasingly (as described by NESO in FRCR documents), experience suggest that batteries with responses as fast and, in aggregate, as large as delivered via the Dynamic Containment service can succeed in complementing and, to some extent, replacing inertial response on the GB power system and, for the largest losses of infeed that are typically encountered, can keep system frequency within acceptable limits. However, there are some differences between these two kinds of response to frequency deviations.

1. For as long as a synchronous machine remains synchronised, inertial response from it is delivered naturally without the need for measurement and actuation by a control system whereas the release or absorption of energy by a battery in response to a difference between a target and actual value of system frequency depends on measurement and active control. However, it is also the case that retention of synchronism for a synchronous generator depends, under more extreme operating conditions, on behaviour of the automatic voltage regulator that controls the machine’s field voltage and the excitation system[17].
2. An inertial response begins to be delivered as soon as a synchronous machine’s speed changes. With a response from battery, response speed is limited by when a change in system frequency can be measured and battery discharge actuated. This means that, for a given loss of infeed event, the initial ROCOF will be higher on a power system with less inertia than on one with more. This is not necessarily a problem, though; if a large enough response can still be delivered quickly enough, the frequency nadir in the lower inertia system can still be acceptable. One caveat is whether the ROCOF would be so high that generators’ protection systems would trip when a high value of ROCOF is measured, making a frequency fall event worse. However, just as an actuated injection of power will experience a measurement

[17] One of the advantages that is sometimes cited for nuclear power stations in comparison with low carbon energy from wind or solar power is that they use synchronous generators and therefore provide inertia. However, infeed loss limits as defined in the SQSS as guides to the design of generator connections were increased some years ago to align with the size of the machines being installed at Hinkley Point C (and, at the time, planned for other new nuclear stations). This has the result that, without other ways of limiting ROCOF and a frequency nadir following a loss of infeed, the *need* for inertia is increased by the design of Hinkley Point C.

delay, so too will ROCOF-based protection, plus any further deliberate delay to avoid nuisance tripping. The higher initial ROCOF in a lower inertia system is therefore not necessarily a problem.

3. A synchronous machine continues to have kinetic energy that is available to the system to provide an inertial response even when the system frequency is lower than would normally be acceptable, provided the machine remains synchronised. In GB, the Grid Code requires that generators remain synchronised only down to 47 Hz; after that, they are permitted to trip[18]. If they do, system collapse is likely to be inevitable. For a battery, once it has been discharged no further response to a low and falling system frequency is possible. It only becomes available to provide a low frequency containment service once it has been recharged, i.e. it has taken energy from the system. However, if it has a non-zero state of charge, in principle a battery can still contribute to low frequency containment even at very low system frequencies.

As the system in GB makes more use of batteries (and, potentially, fast demand side response and rapid changes to interconnector transfers) to provide frequency containment and less use of inertia, it is likely to enhance stakeholder confidence in ongoing system stability if the above differences are explored and discussed more deeply, particularly the third difference, with steps taken to address any significant risks.

6.5 Controller reliability

As has already been noted, power systems based on alternating current that make use of synchronous machines have benefitted from the ‘inertial response’ of those machines in managing frequency deviations and, also, ‘angular stability’ – the potential for one part of the system to lose synchronism with another as voltage angles change – following disturbances. However, power systems have also always depended on actuated control responses, e.g. to manage the excitation of the rotors of synchronous machines and the input of power to those machines, the action of protection, and the control of voltage via reactive compensation and transformers with on-load tap-changers. In the past, these controls were implemented using low current electrical hardware or mechanical devices. In modern power systems, they make use of digital systems and associated software. This approach is common for control systems on wind turbines, solar PV panels, HVDC interconnectors and batteries.

It has always been necessary to assure the reliability of controllers, a fact that is reinforced by evidence of failures of controller hardware or incorrect controller settings as factors contributing to major power system events such as that in GB on 9 August 2019. The use of software – and of power electronics – offers considerable flexibility. However, its reliability in delivering appropriate system responses needs to be assured. This concerns not just its impact on the performance of any single power system asset but the potential for similar software to be used on multiple assets providing both the opportunity for useful system services at many locations and the risk of similar design or implementation errors being present in many places. In principle, robust compliance testing will prevent such errors although this cannot be 100% guaranteed. On the other hand, software updates offer an ability to correct errors.

It becomes increasingly important that the system operator has access up-to-date models of network users’ assets with an appropriate level of detail, and an ability to manage software update processes, not least so that they can remain confident that their models represent

[18] Once system frequency falls as low as 47.5 Hz but remains above 47.0 Hz, generators are obliged to continue operation for only 20 seconds. See sections CC.6.1.3 and ECC.6.1.2.1.2 [7].

what is present out on the power system. Work on modelling of power electronic converters is ongoing within the sector, e.g. in the Grid Code working group “GC0168: Submission of Electro Magnetic Transient (EMT) Models” [22]. Sufficient resources, both within and outside of NESO, need to be devoted to ensuring that current initiatives are brought to timely conclusions and that standard industry practices are clear, appropriate (balancing need for detailed information with the ability to provide and use it and the system risks associated with not having it), up-to-date and reliably followed across the sector.

6.6 Low voltage induced frequency deviation

The levelised cost of electricity produced using wind turbines and solar PV panels has reduced dramatically over the last 20 years and, depending on assumptions for costs of different fuels, is low compared to that of alternative new capacity, and is low carbon. These resources therefore form very attractive means by which the majority of the GB electricity needs might be met in future. However, system issues associated with these resources also need to be addressed. These include not just the variability of the energy supply but also how the particular electrical technologies they use behave.

Wind and solar power and imports of electricity using high voltage direct current (HVDC) transmission are connected to the electricity network using power electronic converters and do not use directly, electromagnetically coupled synchronous machines. They can therefore be thought of as non-synchronous resources. They can be very flexibly controlled but have strict current limits. These limits are most likely to be hit during conditions in which there is a short circuit network fault somewhere near the converter. The impact of that on voltage dips across the network during a short circuit depends on the total capacity of converters near to a fault but, in a future operating condition with a very high ‘system non-synchronous penetration’ (SNSP), could lead to what has been described as a ‘low voltage induced frequency deviation’ [23]. While unlikely to be a problem in the next year or two, the potential impact of that in future years and associated need for Grid Code changes or changes to the holding of Dynamic Containment reserve should be investigated.

6.7 What is an acceptable level of risk?

The FRCR report observes that costs of reducing risks related to system frequency can be quantified in terms of balancing service costs. Ideally, these could be compared with risks that are also quantified in monetary terms. However, as the FRCR report notes, this is difficult. This is both because a ‘value of lost load’ is difficult to quantify in a way that is acceptable to all stakeholders, and because of the rarity of the worst outcome – disconnection of demand – from a frequency disturbance.

The FRCR work uses the depth of a frequency nadir as the metric of impact of a frequency disturbance, with the triggering of LFDD regarded as the worst outcome. This is reasonable.

LFDD is installed as a defence measure: a means of containing the impact of a frequency fall. Without it, the whole GB system could suffer a complete frequency collapse. Subsequent system restoration would be a complex process that depends both on suitable resources being made available in advance, e.g. through system restoration service contracts, and on successful implementation of a restoration plan ‘on the day’. Restoration from a complete system collapse has never been needed in GB but is something that has been needed in other countries. In Europe, the most recent examples are Spain and Portugal in April 2025 and Italy in August 2003[19].

The UK Government has recognised that GB system collapse is a credible risk and has defined a system restoration standard that will take effect from the beginning of 2027 [24]. However, before that, it needs to be ensured that sufficient restoration services will be available and that all parties involved in a restoration process are familiar with the plan and have practised it. My understanding is that regular practice exercises do take place. However, as noted following the 9 August 2019 frequency disturbance and in some subsequent analysis [21], it needs to be ensured that, as the GB system changes, the configuration of LFDD is appropriate to achieve its basic aims.

A complete analysis of system frequency-related risk would take account not only of the likelihood of LFDD bring triggered but also its probability of success in arresting a potential frequency collapse.

It may also be worth considering either what probability of triggering LFDD represents an acceptable risk or how different outcomes might be weighted in a single risk metric quantified for any given operational policy, e.g. certain minimum holdings of Dynamic Containment reserve and system inertia. In this, higher weightings on the worst outcomes might be used. (For some discussion on this idea see, for example, [25]).

[19] A means of assessing the complex array of mechanisms through which a system collapse might occur is described in [27].

7 Conclusions and recommendations

7.1 Main conclusions

In spite of the occurrence of hundreds of unplanned outages on the transmission system every year and the complexities of assessing their impact, there have been very few, transmission originated major loss of load events in GB. Although major losses of demand do occur somewhere in the world from time to time, the industry globally and in GB in particular has been very successful at ensuring reliable supply of electricity from the transmission system. That is, established industry practices have been very successful at limiting risk.

That success comes at a cost that includes the costs of balancing services, the development and maintenance of network infrastructure, and network users' compliance with the Grid Code and, for distribution network users, relevant Engineering Recommendations. It seems appropriate that costs and benefits in the management of system risk are reviewed periodically. This is what FRCR aims to do in respect of one aspect of system operation: the management of system frequency. I find that objective to be entirely reasonable.

There has been quite a lot of talk about 'inverter-based resources', such as wind, solar or interconnectors using high voltage direct current (HVDC), lacking the 'inertia' that conventional power sources – those such as nuclear, hydro and gas-fired power stations that use 'synchronous machines' – have. 'Inertia' refers to the kinetic energy stored in the rotating mass of each machine that is released or absorbed as conditions on the system change (provided the machines' physical rotation remains synchronised with the alternation of voltages on the network). This store of energy helps to smooth out variations of power on the network. However, while very useful, it is not true that it is utterly essential to stable operation of the system: any store of energy will do, provided it can be accessed quickly enough, either to discharge it or charge it, and there is enough of it.

On the GB power system, there will still be a significant amount of inertia for some years to come but, if full use is to be made of available wind and solar power, we need to learn how to stabilise the system with minimal amounts of it. Experience in GB over recent years suggests that NESO has been doing exactly that, making use of batteries to provide rapid frequency containment reserve – Dynamic Containment.

The main conclusions arising from the review described in this report and the foregoing discussion concern four areas.

1. It is right that obstacles to utilisation of renewable energy and reduction of costs of system operation are removed. In broad terms, I agree that this can be done without unduly increasing risk.
2. The principles driving the Frequency Risk and Control Report (FRCR) represent a good general approach to articulation and management of risk, postulating that:
    a. the benefits of reducing system risk should be balanced with the cost of achieving that reduction; and
    b. risk can be quantified in terms of the impact resulting from a particular disturbance multiplied by the probability of that disturbance.

   Furthermore, it seems reasonable that impact in terms of frequency deviation should be quantified in terms of rises above 50.5 Hz and falls (a) below 49.5 Hz and above 49.2 Hz; (b) below 49.2 Hz but above 48.8 Hz; and (c) below 48.8 Hz.
3. The evidence in support of the assertion that reduction in system inertia would not unduly increase system risk is mostly centred on a reasonable set of factors but is

not presented sufficiently clearly to give stakeholders full confidence in the level of risk to which the system is being exposed. This includes evidence that simulations are sufficiently accurate in reproducing a wide range of real events; that probabilities of different disturbances are as they are claimed to be; and that load inertia is a particular value under a wide range of operating conditions. Moreover, some significant factors relating to the impact of disturbances on system frequency are not addressed sufficiently clearly, most notably:

a. the potential for local variations of voltage magnitude and voltage angle to trigger ROCOF or vector shift based Loss of Mains protection on distributed generation; and
b. whether Low Frequency Demand Disconnection (LFDD) as configured today is fit for the purpose of preventing frequency collapse on a system that has low inertia and a large amount of distributed generation that would be disconnected by the action of LFDD relays.

In relation to factors that are not modelled explicitly, it would be reasonable to make some conservative assumptions. In many instances, this seems to have been done but could have been explained more clearly in published FRCR reports.

4. The framing of statutory requirements around management of system frequency is insufficiently clear to ensure that an event investigation could draw firm conclusions about the actions that a system operator was supposed to take.

7.2 Specific views requested in the Terms of Reference

This subsection presents the above main conclusions in relation to the questions posed in the Terms of Reference of this review.

1. **A view on whether the FRCR methodology is sufficiently comprehensive and robust in managing frequency related risk.**

   Is the FRCR Methodology sufficiently comprehensive? Mostly but the lack of clear assessment of regional effects and the fitness for purpose of LFDD are regrettable omissions.

   Is the FRCR Methodology robust? Because of the aspects that have been neglected, the approach cannot be firmly concluded to be robust. However, those aspects can be addressed by suitably conservative, and suitably defended, assumptions.

2. **A view on the robustness of the modelling, data and assumptions underlying the FRCR recommendations; and**

3. **A view on the robustness of the evidence provided by NESO that system frequency can be maintained within acceptable levels for the most credible power infeed losses, with system inertia set at 102 GVAs and the provision of fast frequency response from other sources.**

   Based on what is presented and other modelling of the GB system that I am aware of (especially that in relation to the effectiveness of a fast frequency containment service such as Dynamic Containment[20]), I do *not* conclude that reduction of inertia would entail excessive risk. However, it is hard to say with complete confidence because of omissions in what has been published by NESO, notably the relative lack of validation of simulations and the difficulty of verifying estimates of probabilities.

[20] See, for example, [28].

4. **A view on the robustness of NESO's assertion that there is a 1 in 23-year risk of simultaneous / consequential events causing frequency to fall below 49.2 Hz, i.e. is it likely that the risk is that low?**

   I find it impossible to answer this question given the way the probabilities have been presented in work published by NESO.

5. **Are there other risks not considered by FRCR that should be considered in making the Authority's decision?**

   The main FRCR report acknowledges the potential for distributed energy resources (DER) – generation and storage – to trip as a consequence of disturbances originating on the transmission system and for such trips to increase the impact of a disturbance. However, how much DER would trip depends on the type and settings of the protection it is using, how much is operating at the time of a disturbance and where it is located relative to where the disturbance happens. NESO acknowledges that there is incomplete information on DER protection and capacity. Conservative assumptions might be made on those aspects but there is still a need to simulate system behaviour on a reasonably detailed spatial level in order to understand spatial sensitivities. NESO is using a 'single bus' model of system frequency which lacks such detail. However, such a model can still be useful if suitable – and suitably justified – assumptions are made. This might have been done. However, from what has been published, it is not clear to me that it has.

   The potential for sub-synchronous oscillations (SSO) to cause losses of infeed has seemingly not been addressed by NESO's FRCR work. However, my understanding is that, to date, few SSO incidents in the GB power system in recent years have led to losses of infeed or outfeed.

   The overall risk to the system depends on how LFDD performs on what can be expected to be the rare occasions on which it is triggered. An industry-wide review of performance of LFDD under a wide range of system conditions should be carried out with the results published and steps taken to implement any recommended actions to improve performance at the earliest possible opportunity.

6. **A view on further areas of improvements for NESO / the Authority to consider in future iterations of the FRCR, e.g. whether, with the speed of response from Dynamic Containment, NESO should be evaluating the likely benefits and risks associated with reducing minimum system inertia further.**

   Aside from a high-level description of one historic case study, the FRCR report provides no direct evidence on the effectiveness of Dynamic Containment (DC). My understanding from other work is that it can be extremely effective. A fuller, published evaluation of DC by NESO would be welcome.

   One area of possible emerging risk as the system changes and inverter-based resources (IBRs) become more widely used is the potential for voltage dips during short circuit faults on the network to be so deep across such a wide area that the effective loss of infeed during the dip is big enough for large frequency deviations to occur even without any permanent loss of infeed. That is, there is the potential for low voltage induced frequency deviation in future operating conditions with a significant total 'system non-synchronous penetration' (SNSP). This should be investigated along with the potential for faults to cause large phase angle jumps that trigger disconnections of IBRs.

   Other areas in which I would recommend action are listed in section 7.3.

7. **Any other comments or observations which we should consider while making a decision on FRCR 2025.**

   Broadly speaking, I feel that the general approach NESO has been taking to quantifying risks associated with large deviations of system frequency is a good one and, backed up by clearly communicated results, should suffice to reassure stakeholders that savings in system operation costs can be achieved without undue increases in risk of interruptions of supply to end users of energy.

   From my reading of NESO's published reports on FRCR 2025 and my few meetings with the people involved, I am confident that there is a generally good understanding of the nature of the challenge of assessing risks to system operation and of how to do so in respect of frequency management. Moreover, my understanding is that, in general, where there are uncertainties about probabilities, NESO's intention has been to make conservative assumptions. If it is made clear where such assumptions have been made and there is stronger evidence on probabilities and outcomes across the board, I feel confident that well-informed stakeholders would feel reassured about NESO's management of system frequency, including the recommendation that the minimum level of system inertia can be reduced from the current limit of 120 GVA.s without undue risk.

7.3 Recommendations

The sets of actions presented in the subsections below are recommended for NESO to carry out. They are presented under three headings:

1. as priorities for FRCR 2025;
2. to be carried out in time to inform FRCR 2026.
3. to be carried out to inform subsequent FRCRs.

7.3.1 Priorities for FRCR 2025

1. Revise and re-publish the FRCR 2025 Report and associated Methodology and Data documents to include evidence of validation of simulations and greater clarity on estimation of probabilities and system parameters, noting, in particular, where conservative assumptions have been made and the nature and impact of those assumptions.
2. Publish an update on what the most recent review of LFDD found, what changes were recommended and whether those changes have been carried out.
3. Provide evidence on the effectiveness and reliability of Dynamic Containment (DC) under a wide range of system conditions.

7.3.2 To inform FRCR 2026

1. Investigate the extent to which generators, interconnectors and storage assets fail to ride-through system disturbances in the ways they are required to by the Grid Code and propose ways to improve compliance.
2. Ensure that lessons from the collapse of the power system on the Iberian Peninsula are captured and implemented, including any arising from a review of risks associated with temporary over-voltage that could lead to losses of infeed.
3. Ensure that system modellers and engineers responsible for the development of policy, e.g. on frequency risk management, have convenient access to archives of operational data.
4. Improve how the SQSS panel performs in driving and scrutinising changes to the SQSS.

5. Take steps to improve the clarity of the licence framing of frequency management by reducing or removing ambiguity from the SQSS.

7.3.3 To inform FRCR post-2026

1. Lead a sector-wide update, to be completed during 2026, to the most recent review of LFDD to assess a wide range of likely future system conditions and extend it to address high frequency risks that could lead to rapid falls in system frequency. The sector should ensure that steps recommended to improve performance are implemented in a timely manner.
2. Ensure that NESO has reliable measurement or state estimation in real-time of power flows at every grid supply point [30].
3. Ensure that NESO has reliable data on the type and capacity of distributed generation and storage at every grid supply point and that its dynamic behaviour, including in response to transmission network disturbances, is adequately managed by provisions in the Grid Code and/or Engineering Recommendations such that risks to transmission system stability are acceptable.
4. Take steps to assure: NESO's access to sufficiently detailed models of network users' assets; the reliability of controller software deployed by network users and providers of system services; and adequate management of controller software updates.
5. Investigate the potential for significant low voltage induced frequency deviation in future operating conditions with a significant total 'system non-synchronous penetration' (SNSP).
6. Investigate the potential for faults to cause large phase angle jumps that trigger disconnections of inverter-based resources.
7. Conduct an investigation into wholesale market-related risks to system frequency associated with:
    a. 'smart' tariffs for demand causing coherent switching behaviour among a large number of loads leading to large step changes in demand at the start of a market settlement period, and how such risks might be mitigated, e.g. by imposing small, random delays on the switching of individual loads;
    b. behaviour by generators in receipt of CfDs that cut revenues when the relevant reference price is negative for a successive number of settlement periods.
8. Ensure that risks associated with disconnection and reconnection of large loads are well-managed.
9. Lead a discussion on what combination of probability and impact represents an acceptable or unacceptable risk.

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Annex 1: SQSS definitions of key terms

Table 1: Definitions of key terms for frequency management in GB SQSS v. 1.0

Term	**Definition**
Loss of Power Infeed	The output of a generating unit or a group of generating units or the import from external systems disconnected from the system by a secured event, less the demand disconnected from the system by the same secured event. For the avoidance of doubt if, following such a secured event, demand associated with the normal operation of the affected generating unit or generating units is automatically transferred to a supply point which is not disconnected from the system, e.g. the station board, then this shall not be deducted from the total loss of power infeed to the system. For the purpose of the operational criteria, the loss of power infeed, includes the output of a single generating unit, CCGT Module, boiler, nuclear reactor or DC Link bi-pole lost as a result of an event.
Normal Infeed Loss Risk	That level of *loss of power infeed* risk which is covered over long periods operationally by frequency response to avoid a deviation of system frequency by more than 0.5 Hz. Until reviewed this is 1000 MW.
Infrequent Infeed Loss Risk	That level of *loss of power infeed* risk which is covered over long periods operationally by frequency response to avoid a deviation of system frequency outside the range 49.5 Hz to 50.5 Hz for more than 60 seconds. Until reviewed this is 1320 MW.
Unacceptable Frequency Conditions	These are conditions where: i) the *steady state* frequency falls outside the statutory limits of 49.5 Hz to 50.5 Hz; or ii) a transient frequency deviation on the *MITS* persists outside the above statutory limits and does not recover to within 49.5 Hz to 50.5 Hz within 60 seconds. Transient frequency deviations outside the limits of 49.5 Hz and 50.5 Hz shall only occur at intervals which ought reasonably to be considered as infrequent. It is not possible to be prescriptive with regard to the type of *secured event* which could lead to transient deviations since this will depend on the extant frequency response characteristics of the system which NGC shall adjust from time to time to meet the security and quality requirements of this Standard.

Table 2: Definitions of key terms for frequency management in NETS SQSS v. 2.10

Term	**Definition**
Loss of Power Infeed	The output of a *generating unit* or a group of *generating units* or the import from *external systems* disconnected from the *national electricity transmission system* by a *secured event*, less the demand disconnected from the *national electricity transmission system* by the same *secured event*. For the avoidance of doubt if, following such a *secured event*, demand associated with the normal operation of the affected *generating unit* or *generating units* is automatically transferred to a supply point which is not disconnected from the system, e.g. the station board, then this shall not be deducted from the total *loss of power infeed* to the system. For the purpose of the operational criteria: i the *loss of power infeed* includes the output of a single *generating unit*, CCGT Module, boiler, nuclear reactor or import from an *external system* via a HVDC Link. ii In the case of an *offshore generating unit* or group of *offshore generating units*, the *loss of power infeed* is measured at the *interface point,* or *user system interface point,* as appropriate. iii In the case of an *offshore generating unit* or group of *offshore generating units* for which infeed will be automatically re-distributed to one *interface points* or *user system interface points* through one or more interlinks, the re-distribution should be taken into account in determining the total generation capacity that is disconnected. However, in assessing this re-distribution, consequential losses of infeed that might occur in the re-distribution timescales due to wider generation instability or tripping, including losses at distribution voltage levels, should be taken into account.
Normal Infeed Loss Risk	Until 31 March 2014, this is a *loss of power infeed* risk of 1000 MW. From 1 April 2014, this is a *loss of power infeed* risk of 1320MW.
Infrequent Infeed Loss Risk	Until 31 March 2014, this is a *loss of power infeed* risk of 1320 MW. From 1 April 2014, this is a *loss of power infeed* risk of 1800 MW.
Unacceptable Frequency Conditions	These are conditions where: i the *steady state* frequency falls outside the statutory limits of 49.5 Hz to 50.5 Hz; or ii a transient frequency deviation on the *MITS* does not meet the criteria below. Transient frequency deviations outside the limits of 49.5 Hz and 50.5 Hz shall: - only occur at intervals which ought to reasonably be considered as infrequent. - only persist for a duration which ought to reasonably be considered as tolerable; and

	- only deviate by a magnitude which ought to reasonably be considered as tolerable. The *Frequency Risk and Control Report* will define what is considered reasonable, infrequent and tolerable for each of these criteria for transient frequency deviations. It is not possible to be prescriptive with regard to the type of *secured event* which could lead to transient frequency deviations since this will depend on the extant frequency response characteristics of the system which the *ISOP* adjust from time to time to meet the security and quality requirements of this Standard.
Frequency Risk and Control Report	The periodic report setting out the results of an assessment of the operational frequency risks on the system produced by the *ISOP* and approved by the Authority and as set out in the SQSS Appendix H, and prepared in accordance with the *Frequency Risk and Control Report Methodology* as also prepared and approved as set out in the SQSS Appendix H. The report shall include an assessment of the magnitude, duration and likelihood of transient frequency deviations, forecast impact and the cost of securing the system and confirm which risks will or will not be secured operationally by the *ISOP* in accordance with paragraphs 5.8, 5.11.2, 9.2 and 9.4.2.
Frequency Risk and Control Report Methodology	The methodology by which a *Frequency Risk Control Report* will be developed, consulted on and approved by the Authority, and as set out in the SQSS Appendix H.
Independent System Operator and Planner (*ISOP)*	Means a person designated by the Secretary of State under section 162 of the Energy Act 2023 as the holder of the *ESO licence*, and the *Gas System Planner licence*, for the time being that person is the NESO.

Annex 2: Scope of this review

The Security & Quality of Supply Standard (SQSS) requires the National Energy System Operator (NESO) to produce a Frequency Risk and Control Report (FRCR). The FRCR sets out NESO's general policy for managing frequency risks on the GB electricity system. NESO develops an FRCR Methodology and Report annually, which is consulted upon and then scrutinised by the SQSS Review Panel before it is submitted to the Authority for approval. To complement the Authority's consultation on FCRC, the Authority is seeking an additional independent expert's view before a final decision is made. The Authority requires the consultant to commission this review and has chosen an academic institution to carry it out in order to gain philosophical insights that will inform the Authority's approach.

The Authority requires the Consultant to provide:

1. A view on whether the FRCR methodology is sufficiently comprehensive and robust in managing frequency related risk.
2. A view on the robustness of the modelling, data and assumptions underlying the FRCR recommendations.
3. A view on the robustness of the evidence provided by NESO that system frequency can be maintained within acceptable levels for the most credible power infeed losses, with system inertia set at 102 GVAs and the provision of fast frequency response from other sources.
4. A view on the robustness of NESO's assertion that there is a 1 in 23-year risk of simultaneous / consequential events causing frequency to fall below 49.2Hz, i.e. is it likely that the risk is that low?
5. Are there other risks not considered by FRCR that should be considered in making the Authority's decision?
6. A view on further areas of improvements for NESO / the Authority to consider in future iterations of the FRCR, e.g. whether, with the speed of response from Dynamic Containment, NESO should be evaluating the likely benefits and risks associated with reducing minimum system inertia further.
7. Any other comments or observations which we should consider while making a decision on FRCR 2025.